

Furnace Injection of Alkaline Sorbents for Sulfuric Acid Control

Semi-Annual Technical Progress Report

April 1, 2003 – September 30, 2003

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Abstract

This document summarizes progress on Cooperative Agreement DE-FC26-99FT40718, Furnace Injection of Alkaline Sorbents for Sulfuric Acid Control, during the time period April 1, 2003 through September, 2003. The objective of this project is to demonstrate the use of alkaline reagents injected into the furnace of coal-fired boilers as a means of controlling sulfuric acid emissions. The coincident removal of hydrochloric acid and hydrofluoric acid is also being determined, as is the removal of arsenic, a known poison for NO_x selective catalytic reduction (SCR) catalysts. EPRI, the Tennessee Valley Authority (TVA), FirstEnergy Corporation, American Electric Power (AEP) and the Dravo Lime Company are project co-funders. URS Group is the prime contractor.

This is the eighth reporting period for the subject Cooperative Agreement. During previous reporting periods, two long-term sorbent injection tests were conducted, one on Unit 3 at FirstEnergy's Bruce Mansfield Plant (BMP) and one on Unit 1 at AEP's Gavin Plant. Those tests determined the effectiveness of injecting alkaline slurries into the upper furnace of the boiler as a means of controlling sulfuric acid emissions from these units. The alkaline slurries tested included commercially available magnesium hydroxide slurry (Gavin Plant), and a byproduct magnesium hydroxide slurry (both Gavin Plant and BMP). The tests showed that injecting either the commercial or the byproduct magnesium hydroxide slurry could achieve up to 70-75% overall sulfuric acid removal. At BMP, the overall removal was limited by the need to maintain acceptable electrostatic precipitator (ESP) particulate control performance. At Gavin Plant, the overall sulfuric acid removal was limited because the furnace injected sorbent was less effective at removing SO₃ formed across the SCR system installed on the unit for NO_x control than at removing SO₃ formed in the furnace. The SO₃ removal results were presented in the semi-annual Technical Progress Report for the time period April 1, 2001 through September 30, 2001. Additional balance of plant impact information for the two tests was reported in the Technical Progress Report for the time period October 1, 2001 through March 30, 2002. Additional information became available about the effects of byproduct magnesium hydroxide injection on SCR catalyst coupons during the long-term test at BMP, and those results were reported in the report for the time period April 1, 2002 through September 30, 2002.

During the current period, process economic estimates were developed, comparing the costs of the furnace magnesium hydroxide slurry injection process tested as part of this project to a number of other candidate SO₃/sulfuric acid control technologies for coal-fired power plants. The results of this economic evaluation are included in this progress report.

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Introduction

This document is the semi-annual Technical Progress Report for the project “Furnace Injection of Alkaline Sorbents for Sulfuric Acid Control,” for the time period April 1, 2003 through September 30, 2003. The objective of this project is to demonstrate the use of alkaline reagents injected into the furnace of coal-fired boilers as a means of controlling sulfuric acid emissions. The coincident removal of hydrochloric acid and hydrofluoric acid has also been determined, as has the removal of arsenic, a known poison for NO_x selective catalytic reduction (SCR) catalysts. The project is being funded by the U.S. DOE National Energy Technology Laboratory under Cooperative Agreement DE-FC26-99FT40718. EPRI, the Tennessee Valley Authority (TVA), FirstEnergy Corporation, American Electric Power Company (AEP), and the Dravo Lime Company are project co-funders. URS Group (formerly Radian International) is the prime contractor.

Sulfuric acid is present in most flue gases from coal combustion because a small percentage of the SO₂ produced from the sulfur in the coal (approximately 0.5% to 1.5%) is further oxidized to form SO₃. The SO₃ combines with flue gas moisture to form vapor-phase or condensed sulfuric acid at temperatures below 500°F. Because of this temperature effect, in this report sulfur in this oxidation state is generally referred to as “SO₃” in furnace gas or flue gas upstream of the boiler air heater, and “sulfuric acid” in flue gas downstream of the air heater.

Besides being a Toxic Release Inventory substance and a potential precursor to acid aerosol/condensable emissions from coal-fired boilers, sulfuric acid in the flue gas can lead to boiler air heater plugging and fouling, corrosion in the air heater and downstream, and the formation of a visible plume. These issues will likely be exacerbated with the retrofit of SCR for NO_x control on some coal-fired plants, as SCR catalysts are known to further oxidize a portion of the flue gas SO₂ to SO₃.

The project has tested the effectiveness of furnace injection of four different calcium- and/or magnesium-based alkaline sorbents on full-scale utility boilers for SO₃ control. These reagents have been tested during four one- to two-week tests conducted on two FirstEnergy Bruce Mansfield Plant (BMP) units. One of the sorbents tested was produced from a wet flue gas desulfurization (FGD) system waste stream, from a system that employs a modified Thiosorbic[®] Lime scrubbing process. The other three sorbents are commercially available.

After completing the four one- to two-week tests, the most promising sorbents were selected for two longer-term (up to 30-day) full-scale tests. The longer-term tests were used to confirm the effectiveness of the sorbent tested over extended operation, and to determine balance-of-plant impacts. Two longer-term tests were conducted, one on FirstEnergy’s BMP Unit 3 and the second on AEP’s Gavin Plant Unit 1.

The remainder of this report is divided into five sections: an Executive Summary followed by sections for Experimental procedures, Results and Discussion, Conclusions, and References.

Executive Summary

Summary of Progress

The current reporting period, April 1, 2003 through September 30, 2003, is the eighth technical progress reporting period for this project. October 1, 1999 was the start date for this Cooperative Agreement.

In 2001, a long-term slurry injection test was conducted at BMP Unit 3. The sorbent was a byproduct magnesium hydroxide (byproduct Mg) produced at Allegheny Energy's Pleasants Power Station. The long-term injection test began the second week of May and continued into the first week of June 2001. The primary measure of the success of the slurry injection tests was the reduction in flue gas SO₃ concentration in the electrostatic precipitator outlet flue gas. After the test was complete, samples collected during the test were chemically analyzed, and data collected were organized, reduced and analyzed. Results from this testing were presented in a previous Technical Progress Report for this project (April 1, 2001 through September 30, 2001). The test at BMP included an evaluation of the impacts of byproduct Mg injection in the furnace on SCR catalyst coupons inserted into the flue gas stream at the economizer outlet duct. Analyses and reporting on these coupons were completed during the previous reporting period, and these results are summarized in the Technical Progress Report for the period April 1, 2002 through September 30, 2002.

In July 2001, AEP joined the project as a new team member, co-funder, and host site. Their Gavin Plant started up new SCR units for NO_x control on both Units 1 and 2 (both 1300-MW coal-fired units) in May 2001. As might have been expected, a portion of the SO₂ produced from the high-sulfur coal fired there was oxidized to SO₃ across the SCR catalysts. This conversion essentially doubled the amount of SO₃ in the flue gas going to the units' air heaters, and correspondingly increased sulfuric acid concentrations at the ESP outlet and FGD outlet (stack). The increased sulfuric acid concentrations in the stack flue gas caused increased plume opacity, and appeared to contribute to the occurrence of plume "touch downs" at ground level near the plant. AEP joined the project to test magnesium hydroxide injection as a means of controlling stack sulfuric acid concentrations, and TVA agreed to forego testing on one of their units for the opportunity to test sorbent injection on a unit with an operating, full-scale SCR system.

Because the supply of byproduct Mg in the quantities required to treat two 1300-MW units was in question, AEP also wanted to test commercial magnesium hydroxide (commercial Mg), so that sorbent was used for a portion of the test. The testing at Gavin Plant was conducted from the middle of August through the first week of September. SO₃ removal results from this test were reported in a previous Technical Progress Report for this project (April 1, 2001 through September 30, 2001). Balance-of-plant results from the testing at Gavin Plant were presented in a later Technical Progress Report (October 1, 2001 through March 31, 2002). There are no additional results from the Gavin testing to report for the current period.

During the current period, process economic estimates were developed, comparing the costs of the furnace magnesium hydroxide slurry injection process tested as part of this project to a number of other candidate SO₃/sulfuric acid control technologies for coal-fired power plants.

The results of this economic evaluation are included in this progress report. Also, a paper summarizing these results was presented on September 23rd at the DOE-co-sponsored International Conference on Air Quality IV in Arlington, Virginia.

No subcontracts were issued or completed during the current reporting period.

Problems Encountered

There were no problems encountered during the current reporting period.

Plans for Next Reporting Period

The next reporting period will cover the time period October 1, 2003 through the end of the project period of performance, December 31, 2003. A demonstration of the SBS InjectionTM process is being considered at a commercial installation of the process, at the Tennessee Valley Authority's Widows Creek Unit 7. If this demonstration testing can be arranged and is co-funded as part of this cooperative agreement, it will take place during October. Also during the next reporting period, the final report for the previous magnesium hydroxide injection testing will be submitted to Document Control, and a final report for any testing of the SBS InjectionTM process will be prepared and submitted.

Prospects for Future Progress

Since the new end date for the Cooperative Agreement is December 31, 2003, there are no subsequent reporting periods.

Experimental

An economic evaluation was conducted to compare the projected costs for the furnace injection technologies tested as part of this project to cost estimates for other SO₃ control options. A wide range of SO₃ or sulfuric acid controls have been tested and/or applied for coal-fired power plants, such as low-sulfur-coal switches, injecting alkaline sorbents at various locations in the furnace or ductwork, and installing wet ESPs. The costs of applying these technologies can vary over a wide range, and each has positive and negative attributes that could make it more or less favorable for application at a given power plant. This section describes a number of SO₃/sulfuric acid control technologies and presents the experimental approach used to estimate costs for applying these technologies at an example plant that is being retrofitted with SCR for NO_x control.

Identification of Candidate Technologies

Figure 1 shows the flue gas path of a typical coal-fired power plant, and illustrates where a number of candidate SO₃/sulfuric acid control technologies might typically be applied. The following paragraphs briefly discuss each of the potential control technologies illustrated.

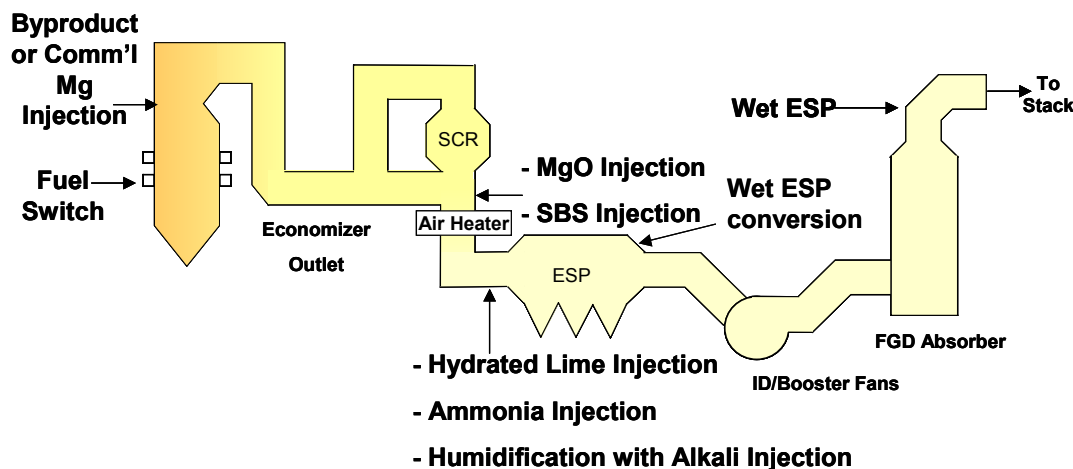


Figure 1. Illustration of Potential SO₃/Sulfuric Acid Control Options

Fuel Switch/Blending

Low-sulfur coal blending or switching lowers the SO₂ content of the flue gas, which reduces the concentration of SO₃ produced in the furnace and across an SCR catalyst. The ability to implement this option and its cost effectiveness can be very site specific. For example, the ability to blend or switch to low-sulfur coal can be limited by issues such as long-term coal contracts, coal mill capacity, furnace slagging and fouling tendencies, ESP performance, etc. Blending can also require room for multiple coal piles and the ability to prepare coal blends in the coal yard, on conveyors, and/or in bunkers. If low-sulfur-coal firing is feasible, though, it can result in other benefits such as making more SO₂ allowance tons available and allowing lower air heater outlet flue gas temperatures, the latter of which can result in plant heat rate improvements.

Notwithstanding capital expenses that may be required, the economics of coal switching are driven almost entirely by the delivered cost differential between the current coal and the low-sulfur coal. Changes in the delivered fuel price of a few cents per million Btu can change the annual costs for this control option by several hundred thousand dollars or more.

Furnace Injection of Magnesium-based Alkalis

This technology, which has been the subject of the current project (DE-FC26-99FT40718), involves injecting magnesium hydroxide ($\text{Mg}(\text{OH})_2$) aqueous slurry into the upper furnace, where it reacts with SO_3 to produce magnesium sulfate solids. These solids are removed in the downstream particulate control device. For this evaluation, cost estimates have been developed for both an FGD byproduct $\text{Mg}(\text{OH})_2$ slurry (byproduct Mg) and commercial $\text{Mg}(\text{OH})_2$ slurry (commercial Mg). Based on unfavorable test results from this project, dolomitic reagents were not considered for furnace injection in the economic evaluation.

Furnace injection can have an advantage over downstream injection technologies for plants that have SCR systems, by lowering flue gas SO_3 concentrations at the SCR inlet. This may allow the SCR to operate at lower unit load and correspondingly reduced SCR inlet flue gas temperature without condensing ammonium bisulfate in catalyst pores. However, furnace injection appears to be relatively ineffective at removing SCR-formed SO_3 from the flue gas.

For plants without SCR, furnace Mg injection is capable of high SO_3 removal percentages, but SO_3 removal may be limited by the performance of downstream cold-side ESPs. At high SO_3 removal percentages, the loss of sulfuric acid conditioning of fly ash particles appears to cause high resistivity conditions that limit ESP performance. With or without SCR, furnace injection should lower the flue gas acid dew point, which may allow the plant to operate at lower air heater outlet flue gas temperatures and realize heat rate improvements, as explained in the following paragraph. The plant may also experience reduced corrosion in downstream equipment, and correspondingly reduced maintenance costs.

The potential benefits of SO_3 removal upstream of the air heater on plant heat rate are mentioned several places in this report, and warrant explanation. Most coal-fired power plants have steam or glycol heaters to preheat the ambient combustion air going to the air heaters. The amount of preheat is adjusted to control the air heater outlet air and flue gas temperatures. On bituminous coal plants, the air heater outlet flue gas temperature is typically controlled to minimize adverse effects of sulfuric acid condensation, such as plugging and/or corrosion in the air heater, or downstream corrosion. Lowering the flue gas SO_3 concentration upstream of the air heater, such as by furnace Mg injection, may allow the plant to lower the air heater outlet temperature. This is typically implemented by reducing the amount of steam used to preheat the combustion air to the air heater (or to heat the glycol solution). Reduced steam consumption for combustion air preheat can improve the overall plant heat rate.

Conversely, in the event of an SCR retrofit, the air heater inlet flue gas SO_3 concentration is increased, which could require more steam preheat to increase the air heater outlet flue gas temperature to compensate for the sulfuric acid dew point elevation. Technologies that remove

SO₃ upstream of the air heater may allow a plant to avoid such an increase after an SCR retrofit, and avoid a heat rate penalty. For this economic evaluation, only the latter benefit, avoided air heater outlet flue gas temperature increase, was considered as part of the economics for technologies that remove SO₃ upstream of the air heater.

Alkali Injection into the SCR Outlet Duct

Costs were estimated for two injection technologies for downstream of the SCR and upstream of the air heater: MgO powder injection and sodium bisulfite/sulfite solution (SBS) injection. These alkalis react with SO₃ to form salts that are removed in the particulate control device. Since these technologies can remove SO₃ upstream of the air heater, they offer a potential for lower air heater gas exit temperatures, with corresponding plant heat rate improvements. They may also reduce corrosion in the air heater and downstream equipment.

The reactive MgO powder is marketed by Martin Marietta, but other vendors may provide similar products. Relatively few performance data are available in the literature for the MgO duct injection process. Martin Marietta literature cites examples of high SO₃ removal efficiency (>80%) with near stoichiometric amounts of MgO being injected.¹ Balance-of-plant impacts have not been reported for the MgO duct injection process. High ash resistivity could be an issue for cold-side ESPs if MgO powder is injected to achieve high SO₃ removal efficiency, as such an effect was seen in furnace Mg injection results from this project.²

The SBS Injection™ process is patented by Codan Development LLC and available by license. SBS solution, a byproduct from sodium-based FGD systems, or commercially available sodium sulfite or bisulfite can be used as a feed material. SBS process performance data are available from full-scale testing at Vectren Corporation's A.B. Brown Station.³ Also, two commercial installations have come on line this year, at FirstEnergy's Bruce Mansfield Plant and TVA's Widows Creek Fossil Plant. Performance data and balance-of-plant impacts for the A.B. Brown tests were documented in the report cited above. High sulfuric acid removal levels are possible (greater than 90%, or down to less than 2 ppmv at the ESP outlet) when injecting at Na:SO₃ mole ratios in the range of 1.5:1 to 2:1. No adverse effects on ESP performance were noted even when removing sulfuric acid down to very low concentrations. Apparently the sodium salts formed condition fly ash resistivity in a manner similar to sulfuric acid. The biggest balance-of-plant impact observed in the A.B. Brown testing was the deposition of damp fly ash and sodium salts in the air heater inlet duct as a result of injection nozzle/lance upsets. The process developers have reportedly made modifications to reduce or eliminate solids deposition.

Alkali Injection into the Air Heater Outlet Duct

Two technologies involving alkali injection into the air heater outlet duct were evaluated in the economic comparison, hydrated lime injection and ammonia injection. These, and all technologies applied downstream of the air heater, offer no potential benefits to SCR turn down or plant heat rate.

EPRI evaluated duct injection of alkali powders such as hydrated lime at pilot scale at their Environmental Control Technology Center (ECTC) in the early 1990s.⁴ Alkaline powders react

with flue gas sulfuric acid to form sulfate salts that are collected with the fly ash in the particulate control device. EPRI found it was possible to achieve high sulfuric acid removal percentages when injecting hydrated lime, sodium bicarbonate, or other dry alkaline powders into the ductwork between the air heater and particulate control device, primarily a cold-side ESP. Two disadvantages were observed for this technology: high sorbent injection rates were required to achieve high SO_3 removal efficiencies (many times the stoichiometric amount), and high ash resistivity resulted when calcium-based alkalis such as hydrated lime were used. High resistivity was not an issue with sodium bicarbonate injection, but the reagent cost and impacts on fly ash waste disposal or sales were seen as an issue when injecting a large excess of sodium salts. A blend of 80% lime/20% sodium bicarbonate was also tested, and appeared to minimize ESP performance impacts at a lower sorbent cost than sodium bicarbonate alone.

Ammonia injection has been tested by many and has been at some plants for sulfuric acid control. Ammonia can be injected between the air heater and cold-side ESP at $\text{NH}_3:\text{SO}_3$ mole ratios in the range of 1.5:1 to 2:1 to achieve high sulfuric acid removal levels (upwards of 95%). Ammonia injection does not adversely affect ESP performance. In fact, ammonia injection is often employed to enhance cold-side ESP performance due to the cohesive properties of the ammonium sulfate/bisulfate salts that form. Furthermore, plants that have SCR systems already have a supply of ammonia on site.

The biggest issue for ammonia injection is its effect on fly ash disposal/reuse. Ammonia slip from SCR systems can result in small quantities of ammonia in the fly ash, but also using ammonia for sulfuric acid control can increase the amount in the fly ash more than tenfold. Ammonia is known to desorb from alkaline solutions containing the ammonium ion. If the fly ash is mixed with FGD byproduct to stabilize the sludge for disposal, ammonia in the ash can strip out and cause significant worker exposure and odor issues. If the fly ash is sold for cement admixture or road base use, worker exposure and nuisance odors can similarly result.

Releases of ammonia odors can also result if the ash is sluiced to an open pond, or if dry-handled fly ash is not quickly covered. Even if airborne releases of ammonia are not a concern, ammonia in fly ash can cause water quality issues. If the fly ash is handled dry and disposed of in a landfill, there is typically a leachate and runoff collection system to handle rainfall on the disposal area. With significant quantities of water-soluble ammonia salts in the fly ash, dissolved ammonia could limit the ability to discharge this leachate without treatment. For plants that sluice their fly ash to a pond and reuse or discharge pond water, the ammonium ion present in the water would also likely require some form of water treatment.

Flue Gas Humidification, With or Without Alkali Injection

In this technology, also tested by EPRI at the ECTC, the flue gas is partially humidified and cooled to below its acid dew point. The sulfuric acid appears to be removed by condensing large acid droplets that can be collected in a cold-side ESP or wet scrubber. In contrast, the rapid quenching of flue gas at the wet-dry interface of a wet scrubber is known to form sub-micron-diameter sulfuric acid droplets that are not effectively scrubbed.

Alkali can also be injected, and serves several apparent purposes. One is to neutralize the sulfuric acid droplets formed, so they are less corrosive to ductwork, ESP collecting plates, etc. Although

humidification is used for fly ash conditioning upstream of ESPs, this is typically under low-sulfur-coal conditions. For high-sulfur-coal conditions, corrosion due to condensed acid in ducts would be a concern. Another reason for alkali injection is to control the fly ash resistivity. When injecting upstream of a cold-side ESP, EPRI found that humidification can result in low fly ash resistivity and a tendency for increased ash re-entrainment emissions, which could be avoided by also injecting a calcium-based alkali.

A number of options are possible for flue gas humidification downstream of the air heater. One is for humidification and alkali injection upstream of an ESP. The flue gas can be humidified and dry hydrated lime powder injected separately, or lime slurry can be injected in one step. EPRI tested both configurations. Alternately, the flue gas can be humidified between the ESP and wet FGD, with water alone or with lime slurry, relying on the FGD absorber to remove the sulfuric acid and/or calcium sulfate droplets formed. The Chemical Lime Company has reportedly conducted full-scale tests of humidification with lime slurry injected upstream of a wet FGD absorber for sulfuric acid control, but results from those tests are not publicly available. A potential concern with lime slurry injection at that location is whether the lime particles are scrubbed at high enough efficiency to avoid particulate emission increases. PreussenElektra (now E.ON) reported the use of humidification (water only) just upstream of a wet FGD absorber as a means of reducing outlet SO_3 concentrations.⁵

Humidification with separate hydrated lime powder injection upstream of the ESP was selected for evaluation in this report. Injection upstream of the ESP was selected because ECTC data for this configuration are readily available, while few data are available for injection upstream of the FGD system. Separate humidification and hydrated lime powder injection was selected over lime slurry injection because flue gas humidification with water and dry hydrated lime powder injection have each been demonstrated to some extent at full scale. The ability to successfully inject lime slurries in flue gas ducts is less demonstrated.

Wet ESP

Wet ESP technology has been in existence for nearly a century, but sulfuric acid control on coal-fired power plants represents a relatively new application. In this control technique, sulfuric acid mist is collected by electrostatic forces in a wetted-plate ESP. The collected mist is washed from the plates either periodically or continuously, and the blow down can go to an FGD system or to a separate system for treatment. To achieve high sulfuric acid removal efficiencies (>80%), the wet ESP could be installed downstream of the wet FGD absorber or could be installed inside the absorber vessel as a replacement for the chevron-style mist eliminator. For lower efficiencies (60 to 80%) it is possible to convert the last field of a conventional dry ESP to wet operation. Wet ESPs can be installed in two configurations: a conventional plate and wire configuration for horizontal gas flow situations, or as a bundle of tubes with wires running down the center of each tube for vertical gas flow situations.

Wet ESP technology solves the limitation on SO_3 control by conventional dry ESPs, where most of the sulfuric acid remains in the gas phase and thus is not collected by electrostatic forces. In a wet ESP downstream of an FGD absorber, the sulfuric acid is all present as a sub-micron mist that is collectable by this mechanism. In a last-field dry ESP conversion, the humidification of

the flue gas in the wet field condenses sulfuric acid so it can be removed by electrostatic forces. The wet environment lowers particle resistivity and allows high power input levels to enhance the removal of sub-micron-diameter mist. Also, wet ESPs can remove other flue gas components that contribute to plume opacity, including fine fly ash particles, unburned carbon or soot, and when installed downstream of wet FGD, scrubber carryover. Removal of the latter can be a benefit in controlling droplet rainout from wet stacks.

Based on discussions with vendors, wet ESP retrofits can have capital costs in the range of \$30 to \$40 per kW for last-field dry ESP conversions, and \$40 to over \$90 per kW for retrofits downstream of existing wet FGD absorbers. Downstream of an existing wet FGD, high capital costs can result because of the lack of available real estate, making for a difficult retrofit in an existing vessel or at an elevated location. Corrosion resistant materials are typically required for the discharge electrodes and collecting plates or tubes, ranging from 316 stainless steel to “C” class alloys. Some wet ESP vendors are testing plastic collecting plates as a way of lowering implementation costs.

By being installed at or near the end of the flue gas path, wet ESPs typically address only plume opacity and particulate emissions, and provide no upstream benefits for air heater exit temperatures or duct corrosion. A wet ESP generates an aqueous waste that must either be treated separately or added to the FGD system. Adding this stream to the FGD system would consume a small amount of FGD reagent to neutralize the acid, and would add sulfates and trace metals that could adversely affect FGD chemistry in low sulfite oxidation systems. On scrubbed units, because the wet ESP would remove both sulfuric acid and calcium-based scrubber carryover, careful control of the water chemistry is needed to avoid gypsum scale formation on collector plates and/or blow down piping. The same is true if calcium-based reagents are used to neutralize the collected acid in the recirculating water used to wet the plates. A wet ESP sized to achieve 90% control of sulfuric acid mist at the scrubber outlet would consume approximately 0.1 to 0.2% of the station’s gross output.

Cost Estimating Approach

Cost estimates were prepared for applying a number of sulfuric acid control options on a hypothetical power plant. The plant has a single 500-MW unit, is located in the Midwest on the Ohio River, and fires a 3.5% sulfur bituminous coal. The plant is retrofitting an SCR system for NO_x control, and has a cold-side ESP for particulate control and a wet FGD system for SO₂ control. The FGD system uses limestone reagent and produces wallboard grade gypsum as a saleable byproduct. The fly ash is handled dry, and during the warm weather “ozone season”, all of the fly ash is sold.

The plant has a pulverized coal boiler that typically converts 1% of the coal sulfur to SO₃. The SCR catalyst guarantee is for no more than 0.75% conversion of SO₂ to SO₃ across the catalyst. Figure 2 summarizes the baseline SO₃/sulfuric acid concentrations at various locations in the flue gas path, with and without the SCR in line.

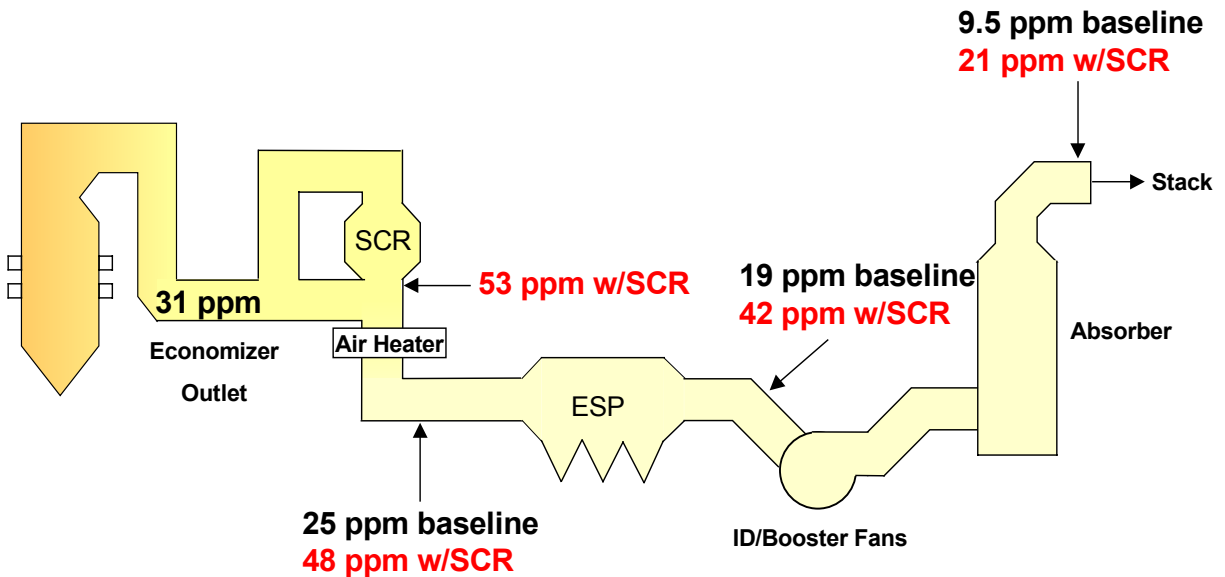


Figure 2. Baseline and Post-SCR SO_3 /Sulfuric Acid Concentrations for Hypothetical Plant

The concentrations in the figure assume approximately 6 ppmv of SO_3 /sulfuric acid removal each across the air heater and ESP and 50% removal of sulfuric acid mist across the FGD absorber for both cases. For the air heater and ESP, it was assumed that the removal is primarily by adsorption on fly ash and that a similar quantity would be adsorbed whether the SCR is in service or not. The removal across the FGD absorber was assumed to be by physical collection, so the percentage removal was assumed to be relatively independent of sulfuric acid mist concentration.

Two levels of sulfuric acid control were evaluated. One was to restore the stack sulfuric acid concentration to the pre-SCR value of 9.5 ppmv (dry basis) from the projected value of 21 ppmv with the SCR in service. An alternate case looks at costs for achieving a higher level of SO_3 control, to 3 ppmv or less at the stack. The lower concentration should be adequate to result in a clear stack, or low stack plume opacity (at least due to the sulfuric acid mist contribution to opacity) under most conditions. The SCR operates only during the “ozone season” from May 1 through September 30, and for both removal levels it was assumed the sulfuric acid controls will only operate during that time period.

Nine potential sulfuric acid controls as described above were considered for this hypothetical plant. Figure 1, shown previously, illustrates the gas path for the plant and indicates where in the gas path these candidate SO_3 /sulfuric acid control technologies were assumed to be installed. The first step in developing cost estimates for these potential sulfuric acid controls was to conduct heat (enthalpy) and material balance calculations. These calculations were used to estimate the expected SO_3 /sulfuric acid control performance of each technology and corresponding reagent and utility consumption rates, for both target removal levels. A number of assumptions had to be made about plant conditions such as capacity factor and coal composition, as summarized in Table 1. Table 2 summarizes the performance bases used for estimating reagent and other consumables quantities for achieving the two SO_3 removal levels for each technology, with the SCR operating. For the furnace injection technologies, the performance estimates were based on

results from this project. For the other technologies, publicly available data were used to estimate performance. Table 3 summarizes the plant operating cost impacts considered for each of the nine control options.

One technology was not estimated for the lower SO₃ removal percentage. Ammonia injection can cause operating problems at lower removal percentages. If ammonia is added at low rates, so as to achieve only the 55% sulfuric acid removal percentage required to meet the 9.5 ppmv stack target, the byproduct would be ammonium bisulfate (NH₄HSO₄). Ammonium bisulfate is sticky and corrosive, and would likely cause ESP operating and maintenance problems. Ammonia is typically added at higher NH₃:H₂SO₄ mole ratios, in the range of 1.5 to 2.0, to predominantly form ammonium sulfate [(NH₄)₂SO₄] which is less sticky and less corrosive. When injected at these mole ratios, 90 to 95% sulfuric acid removal would be expected.

The heat and material balances formed the basis for capital cost estimates for seven of the nine technologies. The exceptions were the wet ESP and fuel switch cases. Capital cost estimates were developed for the wet ESP case, but based solely on general budgetary cost factors. A cost factor of \$35/kW was used for a last-field dry ESP conversion for the lower SO₃ removal target, and a factor of \$55/kW for standalone wet ESP retrofits downstream of the wet FGD absorbers. The capital costs for a wet ESP retrofit can be very site specific, depending on the difficulty of the retrofit and materials of construction selection, and could readily vary by ±50% for a specific circumstance. The capital cost factor of \$35/kW for the lower removal percentage case is based on 316 alloy and the factor of \$55/kW for the higher removal percentage assumes the use of duplex stainless steel alloy.

No capital costs were estimated for fuel switching, as the capital requirements for this technology can be very site specific. Some plants may require little or no capital changes, while other plants may require extensive revisions such as coal blending conveyors, increased mill capacity, soot blower upgrades, ESP enhancements, etc.

For the seven technologies requiring the development of capital cost estimates, sizes for major equipment items such as silos, tanks, pumps, and air compressor were estimated from the material balance results. Storage silos or tanks were sized for 15-day storage at full load and the corresponding SO₃/sulfuric acid removal target. For technologies using a day tank or silo near the unit, this was sized for 24 hours of capacity at full load. Pumps, blowers, and air compressors were also sized based on the material balance results for full load operation. Once sized, the major equipment costs were interpolated from recent URS cost data for similar equipment. Spreadsheets were used to develop overall cost estimates. Piping costs were based on estimated pipe run lengths and standard per-foot cost factors for each pipe size and material. Instrument requirements were based on typical process flow diagrams for each technology. Items such as motor controls were estimated from the number of motors required and valve costs from pipe sizes and the process flow diagrams. Factors were used for estimating costs for process design, detailed design and procurement, installation, construction management, etc. Labor rates were based on Midwest union labor.

Table 1. Assumptions Made for Heat and Material Balances for Model Plant

| Parameter | Value |
|--|---------------------------------------|
| Unit Load (gross MW) | 500 |
| Gross Plant Heat Rate (Btu/hr/KW) | 9200 |
| Capacity Factor (%) | 85 |
| Flue Gas Flow Rate (acfm at economizer outlet) | 2.07×10^6 |
| Coal Sulfur Content (%) | 3.5 |
| Flue Gas SO ₂ Content (ppmv at economizer outlet) | 2790 |
| NO _x Season Duration (months/yr) | 5 |
| Target Stack Sulfuric Acid Concentration (ppmv, dry basis): | |
| For lower SO ₃ removal percentage target | 9.5 (return to pre-SCR conditions) |
| For higher SO ₃ removal percentage target | 3.0 (assumed value for “clear” stack) |

Table 2. Bases for Quantity Estimates for Candidate Control Technologies

| Technology | For 9.5 ppmv at Stack | For 3.0 ppmv at Stack |
|---|---|--|
| Fuel Blending | 32% low-sulfur (0.5 wt%) coal | 87% low-sulfur (0.5 wt%) coal |
| Byproduct Mg Injection in Furnace | 3.9:1 Mg:SO ₃ mole ratio (based on SCR outlet) | - |
| Commercial Mg Injection in Furnace | 3.9:1 Mg:SO ₃ mole ratio (based on SCR outlet) | - |
| MgO Injection Upstream of Air Heater | 1.25 moles Mg injected per mole SO ₃ removed | 1.25 moles Mg injected per mole SO ₃ removed |
| SBS Injection Upstream of Air Heater | 1.0 moles Na injected per mole SO ₃ removed | 1.2 moles Na injected per mole SO ₃ removed |
| NH ₃ Injection Upstream of ESP | Not estimated at lower removal percentage | 1.8 moles NH ₃ injected per mole SO ₃ removed |
| Humidification/Lime Injection Upstream of ESP | Humidification to 293°F, hydrated lime injection at 1 lb/hr per kacfm | Humidification to 275°F, hydrated lime injection at 1 lb/hr per kacfm |
| Hydrated Lime Injection Upstream of ESP | Hydrated lime injection at 2 lb/hr per kacfm | Hydrated lime injection at 5.6 lb/hr per kacfm |
| Wet ESP | Electric power at 320 W/kacfm, water at 0.25 gal/kacf, last field conversion of dry ESP | Electric power at 320 W/kacfm, water at 0.25 gal/kacf, new wet ESP between wet FGD and stack |

Table 3. Summary of SO₃ Control Technology Operating Cost Impacts Evaluated

| | Fuel Switch/Blend | Furnace Injection of Byproduct Mg | Furnace Injection of Commercial Mg | MgO Injection Downstream of SCR | SBS Injection Downstream of SCR | Ammonia Injection Between Air Heater and ESP | Humidificatio n and Lime Injection Between Air Heater and ESP | Hydrated Lime Injection Between Air Heater and ESP | Wet ESP Between FGD Absorber and Stack |
|---|---|---|---|--|---|---|--|---|--|
| Major Power Consumers | None | Air compressors, pumps | Air compressors, pumps | Air blower | Air compressors, pumps | Air blower, heater | Air compressors, pumps, air blower | Air blower | T/R set input power, water pumps |
| Waste Disposal/ Byproduct Stream | Reduced fly ash production due to lower coal ash content; reduced FGD gypsum production | MgSO ₄ , mixed with fly ash | MgSO ₄ , mixed with fly ash | MgSO ₄ , mixed with fly ash | Na ₂ SO ₄ , mixed with fly ash, CaSO ₄ ; increased FGD gypsum production ¹ | (NH ₄) ₂ SO ₄ , NH ₄ HSO ₄ , mixed with fly ash | CaSO ₄ , excess lime mixed with fly ash | CaSO ₄ , excess lime mixed with fly ash | CaSO ₄ , increased FGD gypsum production ² |
| Boiler Efficiency Impacts | Potential increase due to lowered SO ₃ concentration upstream of air heater | Decrease due to water evaporated in furnace, increase due to SO ₃ removal upstream of air heater | Decrease due to water evaporated in furnace, increase due to SO ₃ removal upstream of air heater | Increase due to SO ₃ removal upstream of air heater | Decrease due to water evaporated upstream of air heater, increase due to SO ₃ removal upstream of air heater | None | None | None | None |
| SO ₂ Allowance Impacts | Reduced SO ₂ emissions due to lower coal sulfur | None | None | None | None | None | None | None | None |
| NO _x Removal Impacts | None were evaluated | None were evaluated | None were evaluated | None | None | None | None | None | None |

¹The reaction of SBS or sodium sulfite to remove SO₃ and form sodium sulfate releases an equal molar amount of SO₂ into the flue gas, that must be scrubbed in the FGD absorber.

²Sulfuric acid collected will end up in the FGD liquor, requiring additional FGD limestone for neutralization.

An estimate of this type is typically regarded as having an accuracy of $\pm 25\%$. However, for these estimates the accuracy is more likely in the range of ± 30 to 50% , for a variety of reasons. For example, assumptions were made regarding equipment placement and redundancy that might change during a detailed design effort for an actual plant.

Results and Discussion

Reagent and utility consumption and amortized capital cost estimates were combined to generate annual cost estimates for each control option. The estimates were not levelized to reflect escalation and discount rates, but instead represent first-year costs. Nor do they include operating labor, maintenance labor or materials. For most of the technologies, there is not a good experience basis for estimating these values. The annual cost estimates are summarized in Figure 3 for both removal targets.

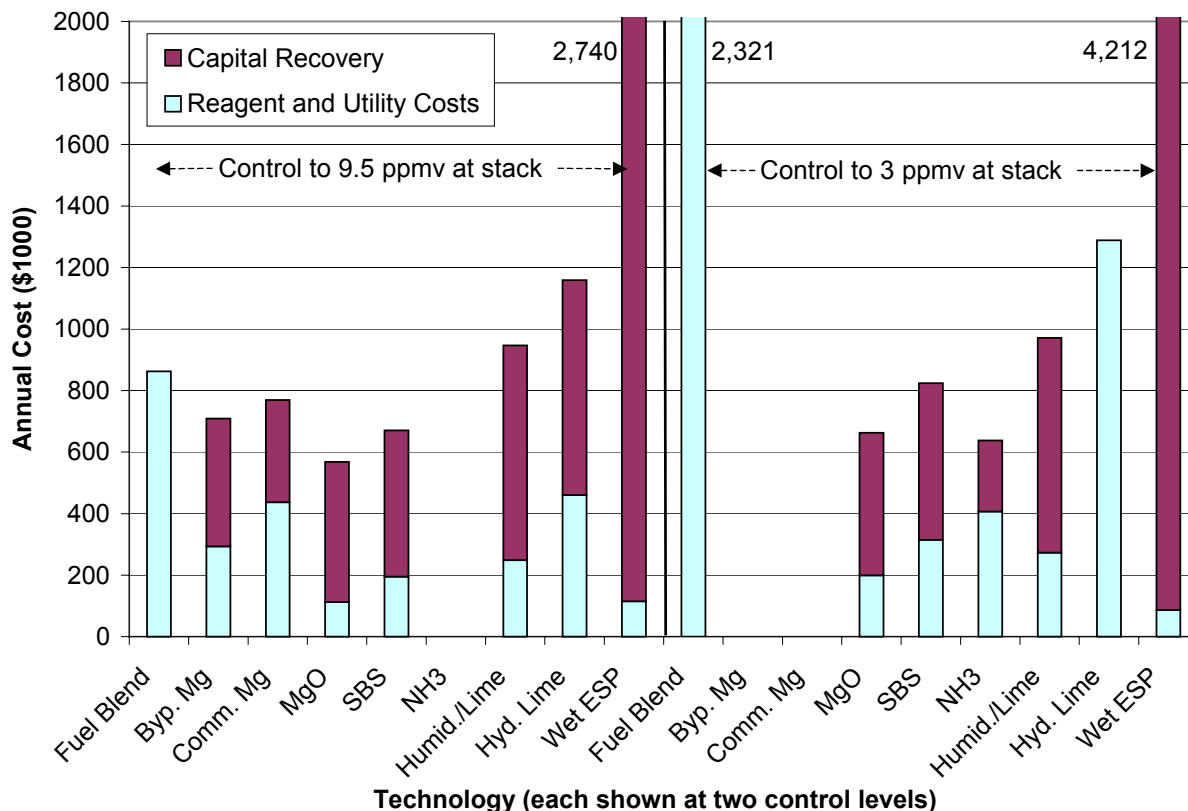


Figure 3. Summary of First-year Capital Recovery and Non-labor Operating Cost Estimates

Reagent and utility costs are based on operating at the target SO_3 control level from May 1 to September 30 each year (the ozone season). The factors used to develop costs from reagent and utility consumption rates are shown in Table 4. Capital recovery is an annual cost irrespective of the months of operation, and is based on a recovery factor of 0.15.

Table 4. Factors Used to Generate Annual Reagent and Utility Costs

| Factor | Value Used |
|--|-------------------|
| Byproduct Mg(OH) ₂ slurry, delivered from Midwest supplier (\$/dry ton of pure Mg(OH) ₂ , shipped at 18% solids, 65% purity in solids, assumed 100-mile delivery distance) | 203 |
| Commercial Mg(OH) ₂ slurry, delivered from Manistee, MI (\$/dry ton Mg(OH) ₂ , shipped at 58 wt% solids, 100% purity in solids, assumed 600-mile delivery distance) | 334 |
| Utilimag 40 MgO powder, delivered from Manistee, MI (\$/dry ton MgO, assumed 600-mile delivery distance) | 422 |
| Sodium Sulfite, delivered from Green River, WY (\$/dry ton available Na as Na ₂ SO ₃) | 300 |
| Ammonia, delivered from existing plant system (\$/ton) | 300 |
| Hydrated Lime powder, delivered from one of various Midwest sites (\$/ton) | 80 |
| Truck Transit Costs (\$/ton-mile) | 0.12 |
| Plant Water Cost (\$/1000 gal) | 0.40 |
| Plant Softened Water Cost (\$/1000 gal) | 2.30 |
| Plant Auxiliary Power (\$/kwh) | 0.032 |
| Plant Fuel Costs (\$/MM Btu) | 1.04 |
| Plant Low-sulfur Fuel Cost (\$/MM Btu) | 1.24 |
| SO ₂ Allowance Value (\$/ton) | 150 |
| Limestone FGD Reagent (\$/ton) | 8.00 |
| Gypsum Byproduct Value (\$/wet ton, f.o.b. plant) | 5.00 |
| Fly Ash Sales Value (\$/ton, f.o.b. plant) | 3.00 |
| Incremental Landfill Disposal Costs (\$/ ton) | 4.00 |
| Capital Recovery Factor | 0.15 |

For the lower sulfuric acid control percentage, MgO powder injection was projected as having the lowest annual cost, at \$570,000. However, no third-party evaluations have been conducted to document the performance of this technology, which adds uncertainty to its performance and cost estimates. Five other control options had projected reagent, utility, and capital recovery costs in the range of \$670,000 to \$950,000 annually per unit. These five include fuel blending, furnace injection of byproduct Mg, furnace injection of commercial Mg, SBS InjectionTM, and humidification with hydrated lime injection between the air heater and ESP. The costs for fuel blending with low-sulfur coal disregard any potential capital modifications that may be required by the plant. Significant capital modification requirements could make this option less attractive.

The differences between the projected costs of these six control options are not great relative to the level of uncertainty for these estimates. For example, if these annual cost estimates are assumed to have an uncertainty of $\pm 25\%$, the “error bars” (not shown in Figure 3) for these six lower cost options would overlap. This suggests that a more detailed analysis would be required to determine the most cost effective control option for this application.

The remaining technologies for which costs were developed at the lower removal percentage include dry hydrated lime powder injection upstream of the ESP, and a wet ESP retrofit to the last field of the existing dry ESP. These two options appear to be less cost effective, with annual costs projected at \$1.2 million and \$2.7 million, respectively. However, the wet ESP comparison is skewed by the assumption that the control technologies will only operate five months out of the year, and the relatively high capital recovery factor (10-year recovery). Both of these assumptions favor low capital cost control options.

For the higher sulfuric acid removal percentage, the estimates show two technologies with projected first-year costs of about \$650,000 (ammonia injection and MgO powder injection). Two other technologies, SBS InjectionTM and humidification with hydrated lime injection, have annual projected costs of \$820,000 to \$970,000. Again, if these annual cost estimates have an uncertainty of $\pm 25\%$, the error bars for these four technologies would overlap.

Two technologies that were projected to be able to achieve the higher removal percentage, fuel switching and dry hydrated lime powder injection, show considerably higher first-year operating costs of \$1.3 million or greater. Capital cost estimates were not prepared for either of these cases. The reason why no capital costs were estimated for fuel switching was previously discussed. For the hydrated lime powder injection case, capital costs were not estimated because the required sorbent injection rate was judged to be prohibitive considering both the sorbent cost and expected adverse effects on ESP performance.

The wet ESP retrofit downstream of the wet FGD system shows the highest first-year cost of over \$4 million. However, as mentioned above, the wet ESP comparison is skewed by the assumption that the control technologies will only operate five months out of the year and the relatively high capital recovery factor (10-year recovery). Both assumptions favor low capital cost control options.

Finally, the two furnace injection technologies were not projected to achieve the higher SO₃/sulfuric acid removal target. Consequently, no results are shown for these technologies on the right side of Figure 3.

The results of this economic comparison are highly dependent on assumptions made about performance, cost and technical issues regarding the potential control technologies. The following describes the factors that affect the cost effectiveness of each technology.

Fuel Blending/Fuel Switch. Costs for this technology are very dependent on the cost differential between the normal plant coal and low-sulfur coal. At the differential of \$0.20 per million Btu used for this evaluation, fuel blending/switching was not cost competitive with some of the injection technologies for the higher sulfuric acid control percentage target. But at a \$0.10 per

million Btu differential it would be cost competitive. This assumes minimal capital cost requirements to be able to blend and fire the low-sulfur coal.

Furnace Injection of Byproduct or Commercial Mg. The costs for this technology are driven by the delivered cost of the Mg reagent, which is dependent on the shipping method and distance. Rail or barge delivery, shorter distances, or (in the case of byproduct Mg) production on site could make this technology more cost effective. Also, for the byproduct Mg, there is not a well-established sales price for this material.

For plants that have an SCR, there are potential benefits from furnace Mg injection that were not evaluated in this comparison. In plants that cycle load, SCR operation may be limited at low load by the formation of ammonium bisulfate that blocks catalyst pores. Economizer bypass ducts or economizer tube bundle removal may be required to maintain high SCR inlet flue gas temperatures at low load. Mg injection to remove furnace-formed SO₃ could allow SCR operation at low unit load without economizer bypasses or tube removal.

MgO Injection Downstream of the SCR. This technology appeared to be cost effective in the economics presented above. However, the performance of this technology was based on a very limited amount of vendor-supplied data, all of which were on flue gases with relatively low uncontrolled SO₃ concentrations (less than 20 ppmv). More data are needed, particularly for higher SO₃ concentrations and preferably measured by a third party, to be able to use these estimates with confidence. As for the Mg slurry injection processes, the costs for this technology will be dependent on the distance from the reagent source. Also, the ability to achieve high SO₃ control efficiencies could be limited by adverse effects on ESP operation.

SBS InjectionTM. A major issue for estimating the cost of this technology is the delivered cost of the reagent, which will be a function of the reagent type, f.o.b. cost, distance and delivery method. For example, the use of a byproduct reagent at a delivered cost of \$200/ton could lower the annual operating cost of this process for the higher SO₃ removal case by approximately 23%. Also, this is a proprietary technology, so the cost estimate includes an annual technology license fee (\$0.20 per kW of generator capacity) not included for the other processes.

Ammonia Injection. This process may not be applicable for many plants because of impacts of the ammonium salts on byproduct handling, reuse or disposal. These economics considered lost fly ash sales revenue and costs for landfill disposing of ammonia-containing fly ash. However, potential costs for removing ammonium ions from landfill leachate or for avoiding nuisance odors during fly ash handling were not included. Such costs could make ammonia injection for sulfuric acid control more expensive than was estimated here. Also, some plant configurations may not be compatible with ammonia injection for sulfuric acid control. Such configurations might include plants that use wet scrubbers for particulate control, that mix ash with FGD byproduct for stabilization, or that sluice and/or pond dispose of fly ash.

Humidification and Lime Injection. The costs for this technology will vary significantly depending on the configuration implemented. If the humidification and alkali injection can be implemented in one step by injecting lime or even limestone slurry into the duct, reagent costs could be reduced by using slaked quicklime or ground limestone rather than hydrated lime

powder. Capital costs would be reduced by eliminating the need for separate humidification and powder handling and injection systems. Also, if the injection is between an ESP and wet scrubber, the excess reagent would be carried into the FGD system, and should reduce FGD reagent consumption.

Hydrated Lime Powder Injection. The performance and cost estimates for this technology are based on ECTC pilot-scale results. There is anecdotal information that others have tested hydrated lime injection at full scale, and have seen lower lime injection rates to achieve a given level of sulfuric acid removal than the ECTC results predict. However, those results were not available to serve as the basis for performance estimates for this evaluation. Even with significantly lower lime requirements, the ability to achieve the higher sulfuric acid control target with this technology remains in question for plants that would inject hydrated lime upstream of ESPs. Removal of sulfuric acid from the flue gas and the injection of high-resistivity, calcium-based solids could significantly degrade ESP performance. Dry injection of a blend of calcium and sodium-based sorbents, as was tested by EPRI, could be employed to overcome adverse effects on ash resistivity, although at a higher sorbent cost.

Wet ESP. Wet ESP retrofit costs will be very site specific, depending on the retrofit difficulty, the required level of sulfuric acid mist control, and the materials of construction. Wet ESP costs should be considerably lower for a new installation than for a retrofit. Regardless of this potential variation, the wet ESP option is the most capital-intensive control technology considered in this evaluation. Wet ESP technology offers an advantage over the other technologies because it can also control fine fly ash or carbon particulate that may contribute to elevated plume opacity. However, since a wet ESP would be installed at or near the end of the flue gas path, it would not address upstream impacts of elevated SO₃/sulfuric acid concentrations such as air heater plugging or corrosion.

Wet ESP technology is the most mature of the control options considered, but is not well demonstrated for the situation at the example plant. Only one full-scale, last-field dry ESP conversion has been implemented in the U.S., at the Mirant Dickerson station, which fires medium-sulfur coal. For the higher sulfuric acid control level, no existing full-scale wet ESP demonstrates all of the example plant criteria: SCR in service, installation downstream of a wet lime or limestone FGD system on high-sulfur coal, and high required sulfuric acid control percentage. Only one existing U.S. installation is close to demonstrating these criteria, at AES' Deepwater plant. There is little doubt that a wet ESP can achieve high sulfuric acid control, with coincident removal of other fine particulate that contribute to plume opacity. However, reliability in a situation such as at the model plant needs to be better demonstrated.

Conclusion

These example economics show that byproduct Mg or commercial Mg injection in the furnace, which were tested as part of this project, can be cost effective for restoring stack sulfuric acid concentrations to pre-SCR levels. The furnace injection technology was not estimated to be able to achieve the higher sulfuric acid removal percentage target with an SCR in operation, though. Ammonia injection was projected to be a low cost technology, but balance-of-plant impacts may preclude its use. MgO injection and SBS injection appear to be cost competitive technologies at either control level. Humidification combined with lime injection may also be a cost-competitive control approach, particularly if the two steps can be combined by injecting lime slurry.

These example economics also demonstrate two important observations about SO₃/sulfuric acid controls. One is that there is no one “best” control option. The cost effectiveness of control options depends on many site specifics. These can include whether an SCR is in service, reagent shipping distances, ash and FGD byproduct reuse/disposal practices, the SO₃ control level required, and the extent to which other particulate matter contributes to plume opacity. Depending on these specifics, one technology may be favored over the others.

The second observation is that there are several candidate SO₃/sulfuric acid control technologies for which there is not adequate full-scale demonstration or test data to serve as a basis for evaluating these technologies. In particular, MgO powder injection and humidification/lime injection technologies (combined or separately) show promise as being cost effective for some situations, but neither has been adequately demonstrated and characterized at full scale.

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